DIRECT TESTIMONY AND EXHIBITS

OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NOS. 2021-143-E AND 2021-144-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission, and distribution ("T&D") planning, and distributed energy resources ("DER"). Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada, and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I have previously testified before this Commission on numerous occasions on behalf of the South Carolina Office of Regulatory Staff ("ORS"). I testified on behalf of ORS regarding Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (collectively, the "Companies" or "Duke" and, individually, a "Company") avoided cost methodologies and regarding other topics in Docket Nos. 2019-185-E, 2019-186-E, 2021-89-E, and 2021-90-E.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analyses, review, and develop recommendations regarding the Companies' applications to establish an EE incentive program for residential solar photovoltaic ("PV") customer-generators.

Q. YOU HAVE TESTIFIED EXTENSIVELY IN SOUTH CAROLINA ON RATEMAKING AND UTILITY AVOIDED COSTS. WHAT IS YOUR EXPERIENCE IN THE AREA OF EE?

A. I worked on EE matters since 1992 as a coauthor to the Electric Power Research Institute report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*. Other highlights include:

- Lead consultant to revise the California Building Energy Codes to support building shell and appliance efficiency improvements since 2005;
- Lead author of framework for PG&E to evaluate energy efficiency programs under the California transition to a restructured electricity generation market;
- Author of DSM2000 report for PG&E on the economic potential for EE using costs that reflect the individual peak demand timing for each of PG&E's 200 distribution planning areas;
- Lead consultant for developing tools and analyses of the use of EE and distributed generation to cost effectively address local capacity needs for utilities including PG&E, Consolidated Edison of New York, Orange and Rockland Utilities, BC Hydro, Ontario Hydro, Commonwealth Edison, Central and Southwest Power, and Nashville Electric Service;
- Contributor to the 2006 US DOE and US EPA *National Action Plan for Energy Efficiency*; and
- Author of the methodology and code used by the CPUC to evaluate all EE programs since 2005 for PG&E, Southern California Edison, and San Diego Gas & Electric.

BACKGROUND

Q. PLEASE SUMMARIZE THE DEC AND DEP PROPOSALS.

A. In keeping with the Memorandum of Understanding ("MOU") Duke signed with the North Carolina Sustainable Energy Association, Sunrun Inc., Vote Solar; and Southern Environmental Law Center on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever (collectively, the "Clean Energy Advocates") in the Solar Choice Metering Tariff dockets, 2020-264-E and 2020-265-E, DEC and DEP propose to classify solar PV as an EE program as part of this proceeding.

Specifically, DEC and DEP propose to give a Solar PV customer-generator an upfront payment incentive of $0.36/Watt-DC. The Companies, in response to ORS data request 3-16, estimate that this would result in average payments of over $3,500 to each qualifying solar PV customer-generator. *See* Exhibit BKH-2, DEC response to ORS data request 3-16. To qualify, a solar PV customer-generator is required to be an all-electric residential customer (i.e., not using natural gas for water heating, cooking, clothes drying, and space conditioning) and agree to participate in the Bring Your Own Thermostat ("Winter BYOT") program for twenty-five (25) years. If a customer unenrolls from the Winter BYOT program before the end of the 25-year requirement or opts out of too many demand response events, the customer must repay the Companies for a prorated share of the initial incentive.

If approved, DEC and DEP not only will be able to collect from their customers the costs of the program including the additional incentive but also shareholder incentives for their expenditures and net lost revenues associated with the solar PV customer-generators as part of the EE program.

Q. WHAT IS THE DEFINITION OF EE?

A. The United States Energy Information Administration ("EIA") defines EE as follows:

> **Energy efficiency** is using technology that requires less energy to perform the same function. Using a light-emitting diode (LED) light bulb or a compact fluorescent light (CFL) bulb that requires less energy than an incandescent light bulb to produce the same amount of light is an example of energy efficiency.[1]

Q. THE COMPANIES ALSO USE THE TERM EE/DSM. WHAT IS EE/DSM?

A. DSM is the acronym for Demand-Side Management. I recall the term DSM coming into widespread use in the 1990s as a broad term to encompass both EE and demand response. Demand response activities include load management activities where customers reduce load for a few hours in response to high system costs or grid operating emergencies. The key difference between demand response and EE is that EE activities are always available to provide efficiency improvements, while demand response only operates for a relatively few hours when called upon or when triggered by external events or price signals. For the purpose of this docket, the term EE/DSM, while technically applicable, is redundant. It is like using the term City/County when one is just focused on the City.

[1] EIA "*Use of energy explained, Energy efficiency and conservation*", https://www.eia.gov/energyexplained/use-of-energy/efficiency-and-conservation.php

REQUEST TO CLASSIFY SOLAR PV GENERATION AS EE

Q. IS IT REASONABLE FOR THE COMPANIES TO OFFER ADDITIONAL EE INCENTIVES TO SOLAR PV CUSTOMER-GENERATORS?

A. No. The Commission can certainly approve incentives for Solar PV, but it should not be done under the guise of solar PV being classified as an EE device. Solar PV is a generation resource, not EE. A solar PV outputs electricity just like a combustion turbine, wind turbine, hydroelectric plant, diesel engine, etc. To be sure, the Solar PV can be located on a customer's roof, but it is still a generator. Indeed, the industry has always recognized that solar PV is not EE, so new terms like Distributed Energy Resources (DER) were coined in the industry to encompass locally sited generators like PV along with EE, demand management, and storage.

As ORS Witness Morgan explains, EE programs qualify for unique treatment of lost revenues and incentives for utility shareholders. Such treatment should not be extended to generators without full and careful consideration and should not be decided outside of an EE proceeding.

Q. DOES DUKE ASSERT THAT SOLAR PV CUSTOMER-GENERATION QUALIFIES AS EE BASED ON S.C. CODE ANN. § 58-37-20?

A. Yes. Duke Witness Timothy Duff states in his Direct Testimony that S.C. Code Ann. § 58-37-20 defines **EE/DSM programs** to specifically include those implemented "for the reduction or more efficient use of energy requirements of the utility or its customers including, but not limited to, . . . renewable energy technologies." Duff Direct, p. 5 (emphasis added).

Q. DOES THE LANGUAGE IN S.C. CODE ANN. § 58-37-20 REFLECT THE LANGUAGE IN MR. DUFF'S DIRECT TESTIMONY?

A. No, it does not. The actual definition from the section is as follows:

> For purposes of this section only, the term **"demand-side activity"** means a program conducted by an electrical utility or public utility providing gas services for the reduction or more efficient use of energy requirements of the utility or its customers including, but not limited to, utility transmission and distribution system efficiency, customer conservation and efficiency, load management, cogeneration, and renewable energy technologies.
> S.C. Code Ann. § 58-37-20 (emphasis added).

A review of the actual Code section shows that it does not define **EE/DSM** as asserted to by witness Duff. Rather, the code defines "**demand side activity**." While the two terms share two common words, they are not equivalent. To be sure, activities that are recognized as EE/DSM are included in the list of demand-side activities, but everything listed as a demand-side activity is not necessarily EE/DSM.

Q. WITNESS DUFF FURTHER ASSERTS ON PAGE 5 THAT SOLAR PV SHOULD BE CONSIDERED EE BECAUSE IT "WOULD LITERALLY REDUCE THE ENERGY REQUIREMENTS OF THE UTILITY AND ITS CUSTOMERS THROUGH RENEWABLE ENERGY TECHNOLOGIES." WHY IS HIS ASSERTION PROBLEMATIC?

A. The problem is that the proposal by the Companies attempts to rebrand generators as EE which may benefit several members of the Clean Energy Advocates through additional incentives for them or their customers and would benefit the Companies by monetizing the energy generated by customer-generators into shareholder incentives.

Witness Duff erroneously tries to draw parallels between Solar PV and actual EE programs by discussing reductions in energy consumption from the Companies grid. However, the actual EE programs result in actual reductions in energy **usage** at the device level – not mere reductions in purchases by customers due to self-generation from the Companies. Higher grade insulation reduces the amount of energy that a customer's heating or cooling system must consume in order to keep the house comfortable. A more efficient heat pump similarly requires less energy to keep the house comfortable. Witness Duff is correct that real EE programs reduce **grid** energy usage – but that is because they reduce **actual** energy usage. A reduction in customer's usage of the Companies grid does not inherently make a program EE, even if the program is a renewable energy technology.

Q. IS IT ACCURATE TO REFER TO SOLAR PV AS "ENERGY EFFICIENCY"?

A. No. Solar PV is self-generation, not EE. Solar PV simply replaces some utility electricity purchases with electricity generated from the Solar PV. Below are two plain language definitions of EE:

1. "Energy efficiency is using technology that **requires less energy** to perform the same function." US Energy Information Agency ("EIA")[2]
2. "Energy efficiency simply means using **less** energy to perform the same task – that is, eliminating energy waste." Environmental and Energy Study Institute ("EESI").[3]

Solar PV fails both definitions of EE. Solar PV is not a technology that reduces the amount of energy that any device in a home consumes, nor does solar PV reduce energy waste

[2] https://www.eia.gov/energyexplained/use-of-energy/efficiency-and-conservation.php

[3] https://www.eesi.org/topics/energy-efficiency/description

within the home. If anything, Solar PV is more accurately characterized as "Energy Replacement" through self-generation, rather than "Energy Efficiency."

Q. DUKE HIGHLIGHTS THE FACT THAT DEC PREVIOUSLY OFFERED INCENTIVES FOR SOLAR DOMESTIC HOT WATER ("DHW") SYSTEMS AS A PART OF THE EE PROGRAM. DO YOU AGREE THAT, BASED ON THIS, SOLAR PV SHOULD ALSO BE DEEMED TO BE EE?

A. No. I am very familiar with solar DHW systems, having spent two years evaluating solar DHW systems for the City of Palo Alto Utility while a student at Stanford University. A solar DHW system operates very differently from a solar PV system. A solar DHW system uses heat from the sun to pre-heat the water for the house. In doing so, it does not generate electricity, but actually increases the energy efficiency of the home's natural gas or electric hot water heater by **reducing the amount** of natural gas or electricity needed to bring the water up to the household's chosen hot water temperature.[4]

To use EIA's definition, the solar DWH system is considered EE because it "uses technology that requires less energy to perform the same function" of delivering hot water. Similarly, the solar DWH system fits the EESI EE definition because the solar pre-heating of the water results in the water heater "using less energy to perform the same task."

In contrast, a Solar PV does not reduce **the amount of energy used** by a customer. Solar PV just reduces the **amount to energy purchased** from the utility because it

[4] Estimating the Cost and Energy Efficiency of a Solar Water Heater, https://www.energy.gov/energysaver/estimating-cost-and-energy-efficiency-solar-water-heater

generates electricity itself. This reduction in energy purchases is not because the customer-generator used less energy, but because the customer "self-generated" the energy.

Q. DO YOU AGREE THAT SELF-GENERATORS THAT REDUCE ENERGY REQUIREMENTS FOR THE UTILITY SHOULD BE CLASSIFIED AS EE?

A. No, I do not. Even in California, which is a leader in energy efficiency, a leader in residential solar, and a leader in EE shareholder incentives (having first established shareholder incentives for EE in 1990), solar is not classified as EE.

There are a myriad of investments or actions that customers can undertake to manage their electricity usage. In my opinion, however, the provisions of S.C. Code Ann. § 58-37-20 related to reducing energy losses and waste should not be applied to energy replacement facilities such as investments in Solar PV. Doing so would contradict long standing, industry-wide, understanding of what constitutes EE to the detriment of all South Carolina utility customers.

Q. PLEASE EXPLAIN HOW THE COMPANIES PROPOSAL TO CLASSIFY SOLAR PV GENERATORS AS AN EE PROGRAM CAUSE HARM TO SOUTH CAROLINA'S USING AND CONSUMING PUBLIC.

A. To answer this question, I created ***Table 1*** which identifies the risks to the Companies' customers and a commentary about how each risk applies to this Docket or to future proceedings:

Table 1
Risks from Classifying Solar PV and EE

Risk	Current or Future Risk
Distorts the magnitude of EE goals and achievements	**Current risk.** Actual EE promotes technology that reduces energy usage, but the ability to reduce usage is generally limited to a small portion of total household usage. Solar PV, on the other hand can generate more than the total annual household usage. Including generator output as EE savings would artificially inflate EE statistics and make the EE program appear to be more effective than it actually is, especially when compared to peer utilities. Inclusion of Solar PV could also potentially reduce efforts for actual EE programs.
Increases costs for all customers through shareholder EE incentives earned by the utility.	**Current Risk.** DEC and DEP earn investor returns on EE programs plus a Shared Savings company incentive. These are additional payments to shareholders that would be funded by utility customers.
Classifying solar PV as EE would create a conflict with the legislative determination that cost shifts from incremental solar should no longer be collected from customers via a rate rider.	**Current Risk.** EE programs recover of up to 36 months of net lost revenues from all customers. This places the entirety of net lost revenues from the qualifying solar PV customer-generators back on the shoulders of other non-solar utility customers.
Opens the door to all types of third-party generators being classified as EE	**Future Risk.** If the Utility Cost Test (UCT) test is the only cost effectiveness that a program is required to pass, then it would be easy for all third-party generators to pass the cost-effectiveness screen which could cost South Carolinians more than traditional utility supply.

Q. WHAT ARE THE PRIMARY RISKS TO THE COMPANIES' SOUTH CAROLINA CUSTOMERS IF SOLAR PV CUSTOMER-GENERATORS ARE CLASSIFIED AS EE/DSM?

A. As discussed in the testimony of ORS Witness Morgan, a Solar EE program would increase costs to DEC and DEP customers by creating unnecessary additional program costs, additional incentives for shareholders, and full recovery of lost revenues. The Companies' customers (solar and non-solar) will fund these additional costs, incentives, shareholder benefits and lost revenue recoveries.

As I discuss later in my testimony, Solar PV does not pass the Companies' cost-effectiveness tests and the additional EE incentive paid to Solar PV customer-generators under the proposed program would further increase costs borne by the Companies' customers as a whole. Also, expanding the definition of EE in the manner the Companies propose could create a path forward or precedent for more alleged "EE" programs that could add further cost burdens to customers in the future.

Q. PLEASE PROVIDE EXAMPLES OF HOW DUKE'S REQUEST TO EXPAND THE DEFINITION OF EE, COULD RESULT IN UNREASONABLE EE PROGRAMS.

A. Consider a customer-sited generator that uses diesel fuel and has a cast iron skillet welded above the combustion chamber. The customer-generator would reduce utility load just like customer-sited solar PV and would provide useful waste heat. An advocate might argue that this is a co-generator that should also qualify as an EE program. Or consider a group of customers at the edge of DEP's territory running extension cords from their refrigerators to their neighbors' houses across the street in Santee Cooper's territory.

Again, this would reduce DEP's utility load and therefore also be considered EE according to Duke interpretation.

To be sure, these examples are whimsical and unrealistic, yet they do spotlight a risk from establishing a precedent for "EE" programs that are clearly not EE programs. Removing the plain language requirement that a device actually improve efficiency in order to be classified as "energy efficiency," is an action that ORS recommends the Commission reject.

COST-EFFECTIVENESS TEST RESULTS

Q. IF THE COMMISSION WERE TO DECIDE TO EXPAND THE DEFINITION OF EE TO ALLOW SOLAR PV, HAS DUKE PROVIDED AN ADEQUATE COST-EFFECTIVENESS JUSTIFICATION FOR ITS ADOPTION?

A. No. Duke attempts to justify its Solar PV EE program based on UCT results. However, the UCT test alone is inadequate to evaluate whether the Solar PV EE program is in the best interests of the Companies customers.

A decision to provide additional incentives to solar customer-generators should be carefully weighed against the cost to the Companies customers. Therefore, it is my opinion that, the cost-effectiveness should be evaluated under multiple perspectives – UCT as proposed by the Companies and the Total Resource Cost ("TRC") test.

DEC and DEC show that the Solar PV as EE program fail the TRC cost-effectiveness test. Moreover, I show later in my testimony that the Solar PV as EE program, when based on more realistic inputs, also fail the UCT cost-effectiveness test for

DEC and DEP. In other words, neither the UCT nor the TRC test support adoption of the Solar PV as EE program.

Q. ALTHOUGH THE COMPANIES' EE PROGRAMS COST EFFECTIVENESS HAVE BEEN MEASURED BASED ON THE TRC TEST, RECENTLY THE COMMISSION IN ORDER NOS. 2021-32 AND 2021-33 DIRECTED THE COMPANIES TO USE THE UCT FOR THE NEW EE/DSM COST RECOVERY MECHANISMS. PLEASE EXPLAIN WHY IS IT IMPORTANT FOR THE COMMISSION TO CONSIDER BOTH THE UCT AND TRC TEST TO EVALUATE THE PROPOSED SOLAR PV EE PROGRAMS.

A. ORS does not support the Companies' proposal that the Solar PV program qualifies as EE. However, should the Commission wish to evaluate the cost-effectiveness of the Solar PV program, ORS recommends the cost-effectiveness be evaluated with both the UCT and the TRC test metrics. It is important to note that the above referenced Orders do not preclude the evaluation and use of the TRC test.

The TRC test is critical for the Commission to determine the impact of a program on the entirety of the using and consuming public. Although the UCT is a valid cost test, it evaluates cost-effectiveness narrowly from the perspective of the utility, and ignores the costs incurred by the participants and non-participants. This narrow perspective that ignores the majority of costs for solar PV, allows the UCT to support a program as being cost effective while the TRC test shows that the solar PV program is not cost-effective.

Additional perspectives on cost effectiveness are particularly important in this case given the significant potential harms posed to customers of Duke's proposed expansion of "EE" coupled with the proposal to add more incentives for solar customer-generators.

Q. CAN YOU PROVIDE MORE DETAIL ON THE DIFFERENCE BETWEEN THE UCT AND TRC TEST?

A. The fundamental difference between the UCT and TRC test is in the costs that are included in each test. For the Solar PV EE program costs, the UCT costs are the **utility incentive costs** and applicable administrative costs. For the TRC Test, the costs are the actual **installed cost** of the Solar PV and applicable administrative costs.

For example, assume an EE device costs $100 and the utility offers a $20 incentive for customers to install the device. Further assume that the EE device provides $60 in benefits. For the cost effectiveness tests, the UCT would have $60 in benefits and $20 in costs, so the benefit cost ratio would be 3.0 (60/20). The TRC test, on the other hand, would have the same $60 in benefits, but the full $100 in costs. The TRC benefit cost ("BC") ratio would only be 0.60 (60/100). Thus, while a UCT test on its face may suggest a program is exceptionally cost effective, a TRC test would reveal that the costs substantially outweigh the benefits of the program and, therefore, would not be reasonable to adopt.

Q. CAN THERE ALSO BE A DIFFERENCE IN BENEFITS FOR THE UCT AND TRC TESTS?

A. Yes. Generally, the benefits for the UCT and TRC tests are the savings from reduced utility costs (the avoided costs) and are the same. For solar PV, however, there are federal tax credits that lower the installed cost of the PV system. The tax credits are treated as increases to the benefits in the TRC calculations. The tax credits are not included as a cost or a benefit in the UCT.

Q. IN YOUR EXPERIENCE IS THE BENEFIT COST RATIO GENERALLY HIGHER UNDER THE UCT THAN THE TRC?

A. Yes. In most cases the utility incentive cost (used for the UCT) is a fraction of the incremental cost of the EE program (used for the TRC). As a result, the UTC typically provides a higher benefit cost ratio and it would be easier for an EE program to pass a UCT >1.0 benefit cost ratio threshold than pass a TRC > 1.0 benefit cost ratio threshold. That is what we see with the DEC and DEP benefit cost ratios for the Solar PV as EE Incentive program.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO ALSO REQUIRE PROGRAMS TO HAVE A TRC BC RATIO THAT IS ABOVE 1.0?

A. The TRC is the only of the four (4) standard cost tests (TRC, UCT, Participant Cost Test, and Ratepayer Impact Measure (RIM) Test) that evaluates the impact of an EE/DSM program on **all customers**. The UCT only looks at the benefits and cost impacts for the utility and ignores the remaining costs that someone else must pay to install Solar PV. The participant test is similarly narrow by focusing only on the program participants, while the RIM test focuses on the non-participants. Only the TRC test focuses on the costs and benefits for all customers (participants and non-participants).

Using the UCT is similar to a grandfather giving his granddaughter $100 to buy a car so he does not have to drive her to high school. It makes economic sense for the grandfather since it saves him gasoline and wear and tear on his car. However, it ignores the fact that her parents are going to end up having to pay for most of the remaining cost of the new car. In this example, the grandfather only considers his costs and his benefits similar to the utility under a UCT test. By only considering a fraction of the economic cost of buying the EE/DSM program (the car in my example), the utility using the UCT can arrive at a flawed conclusion about the cost-effectiveness of a program – just like the grandfather. The TRC, on the other hand, looks at the full cost of the program[5] (i.e., the full cost of the car) in evaluating its cost effectiveness.

Q. SHOULDN'T THE UTILITY FOCUS ON REDUCING ITS COSTS, IN WHICH CASE THE UCT WOULD BE APPROPRIATE?

A. Cost control is certainly a goal and obligation of the utility. In that vein, the UCT is appropriate to consider, but not sufficient by itself. In addition to reducing utility expenditures, utility offered incentives should encourage customer decisions that benefit utility customers as a whole.

The utility should not incent the installation of programs that end up costing South Carolinians more than the benefits they provide[6] – and that is what would happen with a Solar PV EE program that has a TRC less than 1.0 like the programs proposed by the

[5] For simplicity of discussion, I use the term "full cost" to distinguish the cost used in the TRC test versus the incentive cost used in the UCT. The "full cost" of an EE/DSM measure can be the total cost of the measure including installation costs, or could be only the incremental cost of a measure above the cost of the standard efficiency device that it supplants. For the Solar PV, there is no standard efficiency device that would otherwise be installed, so the total cost including installation is appropriate.

[6] The exception being EE programs that are designed to advance non-economic goals such as aid low-income customers.

Companies. That is why it is important to evaluate any program similar to the proposed program using the TRC test. The TRC test results below 1.0 indicates that the Solar PV as EE program would increase costs for all customers.

Q. DUKE STATES THE SOLAR PV TRC BC RATIOS ARE 0.86 FOR DEC AND 0.74 FOR DEP. ARE THE TRC RESULTS CLOSE ENOUGH TO 1.0 TO SUPPORT THE ADOPTION OF THE ADDITIONAL SOLAR PV INCENTIVES?

A. No. Programs with TRC test results below 1.0 are sometimes adopted, but generally that occurs under one of two situations: 1) the programs that fail the cost effectiveness test are part of larger EE portfolios that **are** cost effective in aggregate, and the programs that are not cost-effective are integral to the portfolio; or 2) the programs that fail the cost effectiveness test support social goals such as providing savings for low-income households. Additional incentives for Solar PV customer-generators do not fit either situation.

Moreover, my analysis identified several flaws in the Companies' cost effectiveness analyses, such that the appropriate TRC test results are even lower than DEC's and DEP's calculated numbers of 0.86 and 0.74 respectively.

Q. WHAT FLAWS HAVE YOU IDENTIFIED WITH THE COMPANIES' TRC BC RATIO ESTIMATES?

A. I have found that DEC and DEP have 1) overestimated the T&D benefits of Solar PV, 2) failed to include the cost of solar integration, and 3) failed to use a reasonable estimate of free riders[7].

Q. PLEASE EXPLAIN HOW DUKE OVERESTIMATED THE T&D PEAK REDUCTION PROVIDED BY SOLAR PV AND THEREBY OVERESTIMATED THE T&D BENEFITS OF SOLAR PV.

A. According to DEC's and DEP's responses to ORS data request 4-1, the Companies estimate the T&D benefits of solar PV based on the output of solar in July at the hour ending at 5 pm.[8] However, the Companies did not provide a sufficient rationale for use of that single time period to represent the time of peak demand on the T&D systems.

Indeed, Duke contradicts its use of single time period to represent the entire T&D system in its response to ORS data request 4-10. In that response Duke states that "[w]hile the timings of peaks differ across the system, T&D capacity is planned based on specific winter/summer peaking characteristics observed at the **individual distribution circuit and/or transmission bus level**." [emphasis added] *See* Exhibit BKH-3, DEC response to ORS data request 4-10.

I agree with the statement in Duke's data response that one needs to look at the individual peaks on T&D equipment, and find that the Companies' determination of peak T&D demand reductions using July hour ending at 5 pm is flawed. In the confidential

[7] Free riders in the context of EE refers to customers that would have installed the EE device even if there were no incentive program. As discussed later, the UCT test does not count benefits associated with free riders, so the higher the percentage of free riders, the worse the cost-effectiveness of the EE program.

[8] Response to ORS Data Request 4-1.

response to ORS data request 4-3, DEC and DEP provided the timing of the peaks on their circuits and banks in 2019. That data showed that for DEC [redacted] and for DEP [redacted] *See* Exhibit BKH-4, DEC response to ORS data request 4-3.

To arrive at a more reasonable estimate of solar PV output at the time of the T&D peaks, I calculated the solar PV output at the hour of the peak on each circuit and bank. I then determined a weighted average solar PV output across the DEC and DEP systems. I used the Companies' estimates of residential energy usage on each substation for the weights. In this way, more emphasis is placed on the circuits and banks that have more residential usage and therefore have a higher probability of having solar PV installed. My estimated T&D peak reductions per solar PV installation are 30% lower for DEC and 31% lower for DEP as shown in **Table 2** below. Using the updated T&D peak estimates would further reduce the TRC BC ratios further below 1.0.

Table 2
Solar PV T&D peak reductions

	Company Estimate (kW per installation)	E3 Estimate (kW per installation)	% Change
DEC	2.125	1.494	-30%
DEP	2.125	1.462	-31%

Q. PLEASE EXPLAIN WHY SOLAR PV INTEGRATION COSTS SHOULD BE INCLUDED IN THE EVALUATION OF SOLAR PV COST EFFECTIVENESS.

A. Solar integration costs represent the additional cost burden placed on utility operations due to the intermittent and largely unpredictable nature of solar power. The Commission recognized that solar integration costs reduce the benefits provided by solar generation and thus adopted Solar Integration Services Charges ("SISC") in DEC and DEP's 2019 Avoided Cost Orders of $1.10/MWh for DEC and $2.39/MWh for DEP. The SISC should be incorporated into the cost effectiveness analysis of solar PV as either a reduction in energy benefits or as an increase in costs. Either way, the inclusion of a non-zero SISC would further reduce the cost test benefit cost ratios.

It is worth noting that the SISC was developed based on a focus on utility-scale solar PV generators, not behind-the-meter residential solar customer-generators. The impact of solar output uncertainty and volatility, however, is basically the same. Just as unpredictable reductions in utility-scale solar PV generation could require a utility to have extra generating reserves available, unexpected increases in customer load due to unpredictable reductions in solar energy available to offset onsite usage would also require the utility to have extra generating reserves available.

It is also worth noting that the SISC should only be included in evaluations of solar PV resources. The SISC is unique to the unpredictable operating pattern of solar PV on the DEC and DEP systems and would not be required in the evaluation of EE/DSM programs such as lighting, heating, cooling, or refrigeration.

FREE RIDERS AND THEIR IMPACT ON THE UCT

Q. WHAT CONCERN DO YOU HAVE WITH THE COMPANIES' ESTIMATES OF FREE RIDERS?

A. The Companies' free rider assumptions have a dramatic impact on UCT results. Free riders, in the context of EE, is an estimate of the percentage of participants who would have installed an EE device or undertaken an EE activity even if there were no utility incentive. The concept is that if the incentive program did not exist, the utility would have still received benefits from some customers installing the EE device or undertaking the EE activity on their own. The benefits attributable to the incentive program are therefore only from the incremental customers that would not have installed the EE device or undertaken the EE activity if it were not for the utility offered incentives. The higher the free riders percentage, the less benefits attributable to the incentive program.

Conversely, for the costs counted in the UCT test, there is no reduction for free riders. The utility costs are the same regardless of the number of free riders. A higher free rider percentage lowers the benefits of the program, but does not alter the costs – hence a higher free riders estimate lowers the benefit cost ratio result under the UCT.

Q. PLEASE EXPLAIN WHY THE COMPANIES' ASSUMPTIONS OF 10% FREE RIDERS UNDERESTIMATE THE ACTUAL FREE RIDERS.

A. Generally, such low free riders values are used for programs that would have almost no market uptake without the incentive program. Given that residential solar PV is a well-established technology that has been around for decades, such low market uptake does not likely apply.

The 10% free riders value assumes that residential solar PV installations for all-electric customers will be ten (10) times higher with the incentive program than would have occurred without the incentive program. That is, for every one-hundred (100) customers that receive the Solar PV as EE incentive, ninety (90) of them are installing solar because of the incentive program, and only ten (10) would have installed solar without the program. The Companies assumption of a 10% free riders value is unsupported and unreasonable.

Another way to judge the reasonableness of the Companies' free riders assumption is to directly consider the impact of the incentive on the simple payback period for residential solar PV customer-generators. Using confidential information provided by DEC in the Solar Choice Metering Tariff docket, DEC states that the simple payback period for customers on the successor tariff (the current tariffs) would be about 14.4 years.[9] The proposed additional Solar PV as EE incentive would reduce the simple payback period by about 3.3 years. While a net 11.1 year payback length (14.4 – 3.3) is certainly more attractive than 14.4 years, common intuition as well as research funded by the US Department of Energy[10] say that the improvement in payback length would not incite the ten (10) times the adoptions as required by the DEC 10% free riders assumption.

Similarly, DEP customers on the successor Solar Choice Metering tariff currently see a 16.4 year simple payback, and that would be reduced by 3.8 years to a 12.6 year payback with the proposed additional Solar PV as EE incentive.[11] As with DEC, such a change is unlikely to result in a tenfold increase in residential solar PV adoptions.

[9] Response to ORS Data Request 1-8 in Docket: 2019-170-E.
[10] *Using Willingness to Pay to Forecast the Adoption of Solar Photovoltaics: A "parameterization + calibration" approach*, ://www.osti.gov/servlets/purl/1494980
[11] Response to ORS Data Request 2-2 in Docket Nos. 2020-264-E and 2020-265-E

Q. WHAT FREE RIDERS ASSUMPTION SHOULD BE USED TO EVALUATE THE SOLAR PV AS EE INCENTIVE?

A. As stated earlier, ORS does not support the proposed additional Solar PV incentive be classified as EE. Therefore, a UCT evaluation should not be required. However, should a UCT analysis be conducted, ORS recommends that a free riders percentage of 79% be used in the evaluation.

Q. PLEASE EXPLAIN THE BASIS FOR ORS'S RECOMMENDATION TO USE A 79% FREE RIDERS PERCENTAGE?

A. I derived the free riders percentage using solar PV adoption forecasts provided by the Companies in response to ORS data request 4-4. The data response provided solar PV adoption forecasts under the prior full retail NEM tariffs and forecasted DEC Solar Choice Metering tariffs for solar PV customer-generators.[12] Also, in order to eliminate any possibility that the successor tariff forecasts included any expectation of a Solar PV as EE incentive, I focused on customers on residential rate schedule RS since they would not be eligible for any solar PV as EE incentive. Duke was not able to provide comparable forecast information for DEP, so I use the DEC results for both DEC and DEP.

Based on the current tariffs that do not include a Solar PV as EE incentive, DEC forecasts 497 solar adoptions in 2022 for Schedule RS customers.[13] DEC also forecasts

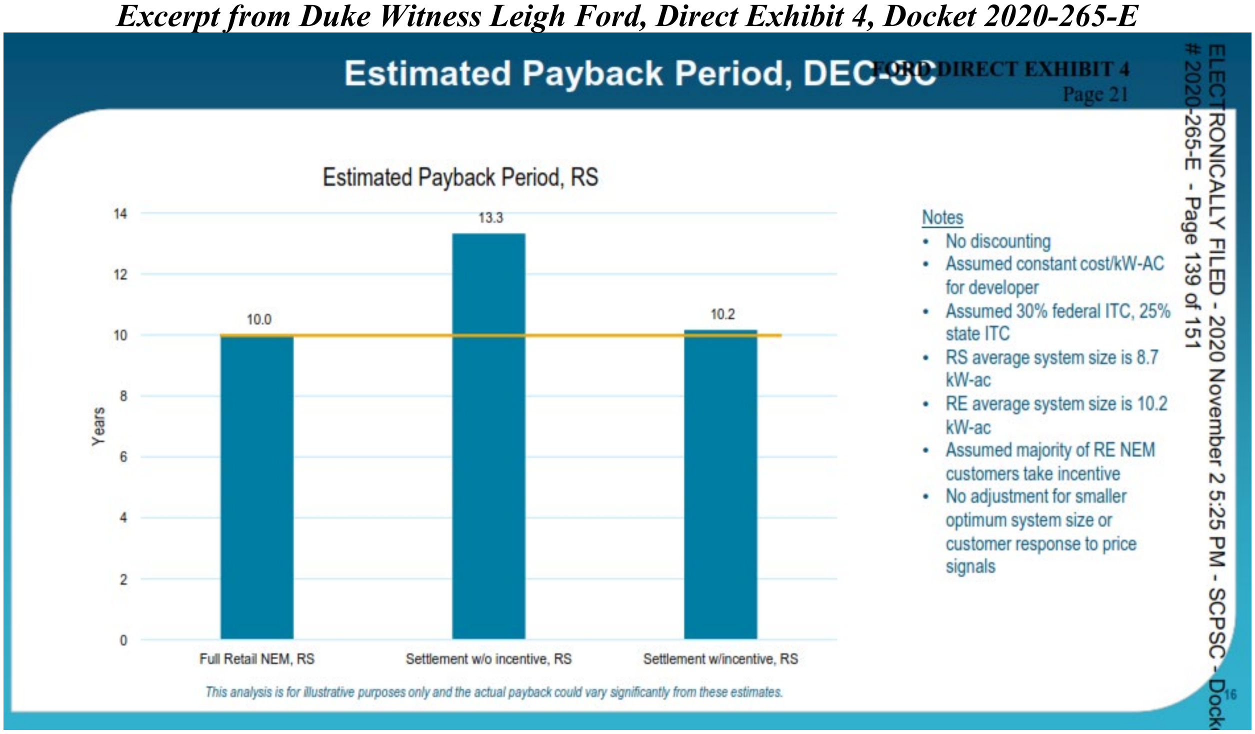
[12] The data response refers to the rates as "proposed rates" which are the Solar Choice Metering Tariffs as proposed at the time. Actual rate component levels may differ slightly from current tariffs.

[13] Forecasts are from DEC's responses to ORS Data Request 4-4.

that there would have been 633 solar adoptions for Schedule RS in 2022 under the prior Full Retail NEM tariffs. *See* Exhibit BKH-5, DEC response to ORS data request 4-4.

I use the 633 solar adoptions as a proxy for adoptions under the current tariffs plus the Solar PV as EE incentive. I can confidently use the 633 adoptions because the current tariffs plus the Solar PV as EE incentive and the Full Retail NEM tariffs provide almost the same estimated payback period for the DEC Schedule RS customers. Duke itself demonstrates this fact in the direct testimony extract shown below from the Solar Choice Metering Tariff docket.

Figure 1
Excerpt from Duke Witness Leigh Ford, Direct Exhibit 4, Docket 2020-265-E



Since there are 497 adoptions without an incentive (current tariffs), and 633 adoptions with the proposed additional Solar PV as EE incentive (the Full Retail NEM tariff proxy), 79% of the solar adoptions (497 / 633) would have occurred without any

Solar PV as EE incentive. In other words, DEC's solar adoption forecasts indicate that the free riders percentage should be far higher than the 10% assumed by both DEC and DEP.

Q. IS THE PROPOSED ADDITIONAL SOLAR PV AS EE INCENTIVE PROGRAM COST EFFECTIVE IF THE FREE RIDERS VALUE RECOMMENDED BY ORS IS USED IN THE UCT EVALUATION?

A. No. Table 3 below shows that using the 79% free riders assumption dramatically reduces the UCT benefit cost results. The Solar PV as EE Incentive program UCT benefit cost ratio drops to far below 1.0 for the Companies, indicating that the program would be far from cost effective. The change in cost effectiveness occurs because the benefits counted in the UCT exclude the benefits attributable to the free riders. This reflects the fact that the benefits from the free riders would have occurred even if the program did not exist, so the actual net benefits provided by the program are the total benefits less the benefits from free riders. In this proceeding, DEC and DEP have excluded only 10% of the estimated benefits of solar PV, while the 79% free rider percentage requires that 79% of the benefits of solar PV be excluded.

Table 3
UCT Benefit Cost ratios for DEC and DEP
using 79% Free Riders (no other corrections)

	10% Free Riders	79% Free Riders
DEC	2.52	0.59
DEP	1.95	0.45

Table 4 and Table 5 below show the derivation of the UCT results shown in Table 3 above. For completeness, Table 4 and Table 5 also show the TRC test results. While the TRC test results remain not cost-effective, the TRC benefit cost ratio is not greatly impacted by the correction in the free riders value compared to the UCT results.

Table 4
DEC UCT and TRC results for79% free riders (no other corrections)

		DEC Filing		ORS Free Rider	
		Free	Benefits	Free	Benefits
	Benefits	Rider	and Costs	Rider	and Costs
1	Avoided Costs (UCT and TRC)	10%	26,479,336	79%	6,178,512
2	Tax Credits (TRC)	10%	20,085,808	79%	4,686,689
	Costs				
3	Admin (UCT and TRC)		762,814		762,814
4	Incentives (UCT)		9,760,226		9,760,226
5	Participant Costs (TRC)	10%	54,396,177	79%	12,692,441
	Utility Cost Test		Total		Total
6	UCT Benefits		26,479,336		6,178,512
7	UCT Costs		10,523,040		10,523,040
8	**UCT Ratio**		**2.52**		**0.59**
	Total Resource Cost Test		Total		Total
9	TRC Benefits		46,565,144		10,865,200
10	TRC Costs		55,158,991		13,455,255
11	**TRC Ratio**		**0.84**		**0.81**

Note: not all benefits and costs apply to both tests, so the components have been labeled to reduce confusion.

Table 5

DEP UCT and TRC results for79% free riders (no other corrections)

		DEP Filing		ORS Free Rider	
		Free Rider	Benefits and Costs	Free Rider	Benefits and Costs
	Benefits				
1	Avoided Costs (UCT and TRC)	10%	3,908,498	79%	911,983
2	Tax Credits (TRC)	10%	3,817,866	79%	890,835
	Costs				
3	Admin (UCT and TRC)		166,730		166,730
4	Incentives (UCT)		1,839,314		1,839,314
5	Participant Costs (TRC)	10%	10,249,774	79%	2,391,614
	Utility Cost Test		Total		Total
6	UCT Benefits		3,908,498		911,983
7	UCT Costs		2,006,044		2,006,044
8	**UCT Ratio**		**1.95**		**0.45**
	Total Resource Cost Test		Total		Total
9	TRC Benefits		7,726,364		1,802,818
10	TRC Costs		10,416,504		2,558,344
11	**TRC Ratio**		**0.74**		**0.70**

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED THE COMPANIES' ASSUMPTIONS THAT RESULT IN OVERESTIMATION OF THE TRC TEST BENEFITS. DO THE UCT RESULTS IN TABLE 4 AND TABLE 5 REFLECT OTHER MODIFICATIONS TO THE COMPANIES' ASSUMPTIONS?

A. No. The impacts of the T&D peak reduction and the cost of solar integration assumptions used by the Companies are small compared to the impact of correcting the Companies' free riders assumption. The results shown in Table 4 and Table 5 reflect only the effect of the free riders assumption.

Table 6 below shows the even lower UCT results if the T&D peak reduction assumptions are corrected and the cost of solar integration is included as a reduction to the avoided cost benefits.

Table 6
UCT for DEC and DEP using 79% Free Riders, T&D peak impact update, and including SISC

	Company	E3 Updated UCT
DEC	2.52	0.53
DEP	1.95	0.42

Q. YOU HAVE SHOWN THE FREE RIDER PERCENTAGE TO BE A CRITICAL ASSUMPTION. WHY HAS IT RECEIVED SO LITTLE ATTENTION IN THE PAST?

A. As I show in my Table 4 and Table 5, the free rider assumption has little impact on the benefit cost ratios of the TRC test. Because the TRC is the primary test in many jurisdictions, including South Carolina until the most recent orders, the free rider assumption has been a non-issue for cost-effectiveness evaluations. For the UCT, however, the free rider assumption is a critical driver of cost-effectiveness. ORS recommends the free riders value be corrected to accurately reflect the Companies forecasted experience.

OTHER

Q. THE COMPANIES PROPOSE THAT ONLY ALL-ELECTRIC RESIDENTIAL CUSTOMERS BE ELIGIBLE FOR THE SOLAR PV EE INCENTIVE. DOES THE EXCLUSION OF CUSTOMERS THAT ALSO USE NATURAL GAS SUGGEST THAT THE IMPACTS OF SUCH A PROGRAM WOULD BE LIMITED TO A SMALL NUMBER OF SOLAR PV CUSTOMER-GENERATORS?

A. No, it does not. For DEP, approximately 67% of their South Carolina customers are all-electric customers and 45% of DEC's customers are all-electric customers.[14] *See* Exhibit BKH-6, DEC response to ORS data request 4-9. All-electric customers are not a small minority of the Companies' residential customers, so the impact of any proposed additional Solar PV as EE incentive program could be large. This is not a limited program like the solar hot water heater EE pilot, but a very large-scale program that could result in substantial costs for non-participants as well as increased shareholder earnings if adopted.

Q. PART OF DUKE'S PROPOSAL IS THAT THE PROGRAM PARTICIPANTS ALSO ENROLL IN THE WINTER BYOT PROGRAM FOR 25 YEARS. SHOULD THE BENEFITS OF CUSTOMERS PARTICIPATING IN THAT PROGRAM BE CONSIDERED IN THE EVALUATION OF THE COST EFFECTIVENESS OF THE PROPOSED ADDITIONAL SOLAR PV AS EE INCENTIVE PROGRAM?

A. The benefits of BYOT participation could be included, but if they were, the costs associated with the program would also need to be included. The current proposal by the Companies excluded both the benefits and costs of the BYOT program, which is a reasonable approach as well.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Before the Commission is a decision to approve or deny the Companies' proposed Solar PV as EE Incentive program. It is ORS's recommendation the Companies' proposed Solar PV as EE Incentive program should be rejected for the following reasons:

[14] Response to ORS Data Request 4-9.

1) Solar PV is generation and should not be classified as EE. It should not be funded via traditional EE mechanisms which contribute to utility shared savings or other shareholder incentive mechanisms embedded in traditional EE programs.

2) If the Commission considers the Companies' proposed programs, the cost effectiveness of the program should be evaluated from two perspectives --- the UTC and TRC test to ensure the cost tests measure the impacts to on the customers as a whole.

3) If the Commission considers the Companies proposed programs, the corrections to the UCT test calculation recommended by ORS should be approved to correct for the underestimation of free riders.

In summary, the ORS recommends rejection of the proposed additional Solar PV as EE Incentive programs

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the “E3 Calculator” tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model’s sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

<u>Cost of Service and Rate Design:</u>

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

<u>Transmission Planning and Pricing:</u>

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA

B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
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Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 3-16

Docket No. 2021-143-E
Docket No. 2021-144-E

Date of Request: **August 25, 2021**
Date of Response: **September 7, 2021**

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The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Bill Eberle, Lead DSM & Retail Programs Analyst, and was provided to the SC Office of Regulatory Staff under my supervision.

Samuel J. Wellborn
Counsel
Duke Energy Carolinas, LLC & Duke Energy Progress, LLC

SC Office of Regulatory Staff
Third Audit Request for Records
and Information
DEC Solar as EE-Docket 2021-144-E
DEP Solar as EE-Docket 2021-143-E
Item No. 3-16
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

3-16 What is the average amount of the incentive DEP and DEC expect to provide each customer that elects to participate in the proposed Smart $aver program(s)?

Response:

DEC's expected average per-participant incentive is $3,585.60.

DEP's expected average per-participant incentive is $3,513.60.

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Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 4-4

Docket No. 2021-143-E
Docket No. 2021-144-E

Date of Request: September 1, 2021
Date of Response: September 10, 2021

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Jason D. Martin, DET Strategy & Policy Director, and was provided to the SC Office of Regulatory Staff under my supervision.

Samuel J. Wellborn
Counsel
Duke Energy Carolinas, LLC & Duke Energy Progress, LLC

SC Office of Regulatory Staff
Fourth Audit Request for Records
and Information
DEC Solar as EE-Docket 2021-144-E
DEP Solar as EE-Docket 2021-143-E
Item No. 4-4
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

4-4 Provide all draft or final solar adoption forecasts under the new Solar Choice Metering (or similar) tariffs for customers not eligible for the solar incentive, (i.e., non-RE customers). The response should include ANY forecasts prepared within the Company (e.g., for load forecast or planning purposes) and not limited to forecasts prepared for this proceeding.

Response:

The attached file is a the forecast for the customers not eligible for the solar incentive. The forecast is based upon information for DEC because there is the rate RS for customers that do not have electric heat. DEP does not have a separate rate classification for residential customers.

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Notes:

The analyses were performed only for DEC and the data is specific to RS customers
The forecast represents a point in time estimate
The rebate data represents the customers and capacity associated with the rebate program from Act 236
The actuals data represents the customers and capacity of non-rebate customers at the time of the analysis
The rebate and actuals remain constant throughout the forecast - assumes the rebate program from Act 236 was fully subscrik
Scenario A - the model data reflects a full retail net metering scenario
Scenario B - the model data reflects aspects of the proposed tariff, featuring a minimum bill requirement and no incentive for
Scenario C - the model data reflects aspects of the proposed tariff, featuring a minimum bill requirement and no incentive for

ɔed and there is no attrition

RS customers - also assumes the monthly bill savings will grow throughout the forecast period
RS customers - assumes no growth in the monthly bill savings throughout the forecast period

	RS Cumulative Counts			
	Rebate	Actuals	Model	Totals
<=2020	1,940	2,952	144	5,036
<=2021	1,940	2,952	740	5,632
<=2022	1,940	2,952	1,373	6,265
<=2023	1,940	2,952	2,009	6,901
<=2024	1,940	2,952	2,645	7,537
<=2025	1,940	2,952	3,269	8,161
<=2026	1,940	2,952	3,902	8,794
<=2027	1,940	2,952	4,552	9,444
<=2028	1,940	2,952	5,216	10,108
<=2029	1,940	2,952	5,894	10,786
<=2030	1,940	2,952	6,578	11,470
<=2031	1,940	2,952	7,271	12,163
<=2032	1,940	2,952	7,967	12,859
<=2033	1,940	2,952	8,667	13,559
<=2034	1,940	2,952	9,375	14,267
<=2035	1,940	2,952	10,083	14,975
<=2036	1,940	2,952	10,799	15,691
<=2037	1,940	2,952	11,519	16,411
<=2038	1,940	2,952	12,239	17,131
<=2039	1,940	2,952	12,967	17,859
<=2040	1,940	2,952	13,699	18,591
<=2041	1,940	2,952	14,435	19,327
<=2042	1,940	2,952	15,179	20,071
<=2043	1,940	2,952	15,923	20,815
<=2044	1,940	2,952	16,667	21,559
<=2045	1,940	2,952	17,423	22,315
<=2046	1,940	2,952	18,179	23,071
<=2047	1,940	2,952	18,942	23,834
<=2048	1,940	2,952	19,710	24,602
<=2049	1,940	2,952	20,478	25,370
<=2050	1,940	2,952	21,246	26,138

	RS Cumulative Capacity			
	Rebate	Actuals	Model	Totals
2020	16.3	23.1	1.2	40.6
2021	16.3	23.1	6.4	45.8
2022	16.3	23.1	11.9	51.3
2023	16.3	23.1	17.4	56.8
2024	16.3	23.1	23.0	62.3
2025	16.3	23.1	28.4	67.8
2026	16.3	23.1	33.9	73.3
2027	16.3	23.1	39.5	78.9
2028	16.3	23.1	45.3	84.7
2029	16.3	23.1	51.2	90.5
2030	16.3	23.1	57.1	96.5
2031	16.3	23.1	63.1	102.5
2032	16.3	23.1	69.2	108.5
2033	16.3	23.1	75.2	114.6
2034	16.3	23.1	81.4	120.8
2035	16.3	23.1	87.5	126.9
2036	16.3	23.1	93.7	133.1
2037	16.3	23.1	100.0	139.4
2038	16.3	23.1	106.2	145.6
2039	16.3	23.1	112.6	151.9
2040	16.3	23.1	118.9	158.3
2041	16.3	23.1	125.3	164.7
2042	16.3	23.1	131.8	171.1
2043	16.3	23.1	138.2	177.6
2044	16.3	23.1	144.7	184.1
2045	16.3	23.1	151.2	190.6
2046	16.3	23.1	157.8	197.2
2047	16.3	23.1	164.4	203.8
2048	16.3	23.1	171.1	210.5
2049	16.3	23.1	177.7	217.1
2050	16.3	23.1	184.4	223.8

	RS Incremental Counts			
	Rebate	Actuals	Model	Totals
2021	0	0	596	596
2022	0	0	633	633
2023	0	0	636	636
2024	0	0	636	636
2025	0	0	624	624
2026	0	0	633	633
2027	0	0	650	650
2028	0	0	664	664
2029	0	0	678	678
2030	0	0	684	684
2031	0	0	693	693
2032	0	0	696	696
2033	0	0	700	700
2034	0	0	708	708
2035	0	0	708	708
2036	0	0	716	716
2037	0	0	720	720
2038	0	0	720	720
2039	0	0	728	728
2040	0	0	732	732
2041	0	0	736	736
2042	0	0	744	744
2043	0	0	744	744
2044	0	0	744	744
2045	0	0	756	756
2046	0	0	756	756
2047	0	0	763	763
2048	0	0	768	768
2049	0	0	768	768
2050	0	0	768	768

	RS Incremental Capacity			
	Rebate	Actuals	Model	Totals
2021	0.0	0.0	5.2	5.2
2022	0.0	0.0	5.5	5.5
2023	0.0	0.0	5.5	5.5
2024	0.0	0.0	5.5	5.5
2025	0.0	0.0	5.4	5.4
2026	0.0	0.0	5.5	5.5
2027	0.0	0.0	5.6	5.6
2028	0.0	0.0	5.8	5.8
2029	0.0	0.0	5.9	5.9
2030	0.0	0.0	5.9	5.9
2031	0.0	0.0	6.0	6.0
2032	0.0	0.0	6.0	6.0
2033	0.0	0.0	6.1	6.1
2034	0.0	0.0	6.1	6.1
2035	0.0	0.0	6.1	6.1
2036	0.0	0.0	6.2	6.2
2037	0.0	0.0	6.2	6.2
2038	0.0	0.0	6.2	6.2
2039	0.0	0.0	6.3	6.3
2040	0.0	0.0	6.4	6.4
2041	0.0	0.0	6.4	6.4
2042	0.0	0.0	6.5	6.5
2043	0.0	0.0	6.5	6.5
2044	0.0	0.0	6.5	6.5
2045	0.0	0.0	6.6	6.6
2046	0.0	0.0	6.6	6.6
2047	0.0	0.0	6.6	6.6
2048	0.0	0.0	6.7	6.7
2049	0.0	0.0	6.7	6.7
2050	0.0	0.0	6.7	6.7

RS Cumulative Counts					RS Cumulative Capacity				
	Rebate	Actuals	Model	Totals		Rebate	Actuals	Model	Totals
<=2020	1,940	2,952	138	5,030	2020	16.3	23.1	1.2	40.6
<=2021	1,940	2,952	624	5,516	2021	16.3	23.1	5.4	44.8
<=2022	1,940	2,952	1,121	6,013	2022	16.3	23.1	9.7	49.1
<=2023	1,940	2,952	1,625	6,517	2023	16.3	23.1	14.1	53.5
<=2024	1,940	2,952	2,126	7,018	2024	16.3	23.1	18.5	57.8
<=2025	1,940	2,952	2,611	7,503	2025	16.3	23.1	22.7	62.0
<=2026	1,940	2,952	3,109	8,001	2026	16.3	23.1	27.0	66.4
<=2027	1,940	2,952	3,625	8,517	2027	16.3	23.1	31.5	70.8
<=2028	1,940	2,952	4,159	9,051	2028	16.3	23.1	36.1	75.5
<=2029	1,940	2,952	4,714	9,606	2029	16.3	23.1	40.9	80.3
<=2030	1,940	2,952	5,278	10,170	2030	16.3	23.1	45.8	85.2
<=2031	1,940	2,952	5,845	10,737	2031	16.3	23.1	50.7	90.1
<=2032	1,940	2,952	6,421	11,313	2032	16.3	23.1	55.7	95.1
<=2033	1,940	2,952	7,004	11,896	2033	16.3	23.1	60.8	100.2
<=2034	1,940	2,952	7,592	12,484	2034	16.3	23.1	65.9	105.3
<=2035	1,940	2,952	8,187	13,079	2035	16.3	23.1	71.1	110.4
<=2036	1,940	2,952	8,787	13,679	2036	16.3	23.1	76.3	115.7
<=2037	1,940	2,952	9,396	14,288	2037	16.3	23.1	81.6	120.9
<=2038	1,940	2,952	10,008	14,900	2038	16.3	23.1	86.9	126.3
<=2039	1,940	2,952	10,627	15,519	2039	16.3	23.1	92.2	131.6
<=2040	1,940	2,952	11,251	16,143	2040	16.3	23.1	97.7	137.0
<=2041	1,940	2,952	11,881	16,773	2041	16.3	23.1	103.1	142.5
<=2042	1,940	2,952	12,517	17,409	2042	16.3	23.1	108.6	148.0
<=2043	1,940	2,952	13,156	18,048	2043	16.3	23.1	114.2	153.6
<=2044	1,940	2,952	13,804	18,696	2044	16.3	23.1	119.8	159.2
<=2045	1,940	2,952	14,453	19,345	2045	16.3	23.1	125.5	164.8
<=2046	1,940	2,952	15,113	20,005	2046	16.3	23.1	131.2	170.6
<=2047	1,940	2,952	15,773	20,665	2047	16.3	23.1	136.9	176.3
<=2048	1,940	2,952	16,443	21,335	2048	16.3	23.1	142.7	182.1
<=2049	1,940	2,952	17,115	22,007	2049	16.3	23.1	148.6	187.9
<=2050	1,940	2,952	17,795	22,687	2050	16.3	23.1	154.5	193.8

	RS Incremental Counts					RS Incremental Capacity			
	Rebate	Actuals	Model	Totals		Rebate	Actuals	Model	Totals
2021	0	0	486	486	2021	0.0	0.0	4.2	4.2
2022	0	0	497	497	2022	0.0	0.0	4.3	4.3
2023	0	0	504	504	2023	0.0	0.0	4.4	4.4
2024	0	0	501	501	2024	0.0	0.0	4.3	4.3
2025	0	0	485	485	2025	0.0	0.0	4.2	4.2
2026	0	0	498	498	2026	0.0	0.0	4.3	4.3
2027	0	0	516	516	2027	0.0	0.0	4.5	4.5
2028	0	0	534	534	2028	0.0	0.0	4.6	4.6
2029	0	0	555	555	2029	0.0	0.0	4.8	4.8
2030	0	0	564	564	2030	0.0	0.0	4.9	4.9
2031	0	0	567	567	2031	0.0	0.0	4.9	4.9
2032	0	0	576	576	2032	0.0	0.0	5.0	5.0
2033	0	0	583	583	2033	0.0	0.0	5.1	5.1
2034	0	0	588	588	2034	0.0	0.0	5.1	5.1
2035	0	0	595	595	2035	0.0	0.0	5.2	5.2
2036	0	0	600	600	2036	0.0	0.0	5.2	5.2
2037	0	0	609	609	2037	0.0	0.0	5.3	5.3
2038	0	0	612	612	2038	0.0	0.0	5.3	5.3
2039	0	0	619	619	2039	0.0	0.0	5.4	5.4
2040	0	0	624	624	2040	0.0	0.0	5.4	5.4
2041	0	0	630	630	2041	0.0	0.0	5.5	5.5
2042	0	0	636	636	2042	0.0	0.0	5.5	5.5
2043	0	0	639	639	2043	0.0	0.0	5.5	5.5
2044	0	0	648	648	2044	0.0	0.0	5.6	5.6
2045	0	0	649	649	2045	0.0	0.0	5.6	5.6
2046	0	0	660	660	2046	0.0	0.0	5.7	5.7
2047	0	0	660	660	2047	0.0	0.0	5.7	5.7
2048	0	0	670	670	2048	0.0	0.0	5.8	5.8
2049	0	0	672	672	2049	0.0	0.0	5.8	5.8
2050	0	0	680	680	2050	0.0	0.0	5.9	5.9

RS Cumulative Counts					RS Cumulative Capacity				
	Rebate	Actuals	Model	Totals		Rebate	Actuals	Model	Totals
<=2020	1,940	2,952	136	5,028	2020	16.3	23.1	1.2	40.6
<=2021	1,940	2,952	583	5,475	2021	16.3	23.1	5.1	44.4
<=2022	1,940	2,952	1,022	5,914	2022	16.3	23.1	8.9	48.3
<=2023	1,940	2,952	1,458	6,350	2023	16.3	23.1	12.7	52.0
<=2024	1,940	2,952	1,880	6,772	2024	16.3	23.1	16.3	55.7
<=2025	1,940	2,952	2,277	7,169	2025	16.3	23.1	19.8	59.1
<=2026	1,940	2,952	2,679	7,571	2026	16.3	23.1	23.3	62.6
<=2027	1,940	2,952	3,098	7,990	2027	16.3	23.1	26.9	66.3
<=2028	1,940	2,952	3,533	8,425	2028	16.3	23.1	30.7	70.0
<=2029	1,940	2,952	3,982	8,874	2029	16.3	23.1	34.6	73.9
<=2030	1,940	2,952	4,438	9,330	2030	16.3	23.1	38.5	77.9
<=2031	1,940	2,952	4,894	9,786	2031	16.3	23.1	42.5	81.9
<=2032	1,940	2,952	5,350	10,242	2032	16.3	23.1	46.4	85.8
<=2033	1,940	2,952	5,806	10,698	2033	16.3	23.1	50.4	89.8
<=2034	1,940	2,952	6,262	11,154	2034	16.3	23.1	54.4	93.7
<=2035	1,940	2,952	6,718	11,610	2035	16.3	23.1	58.3	97.7
<=2036	1,940	2,952	7,174	12,066	2036	16.3	23.1	62.3	101.7
<=2037	1,940	2,952	7,630	12,522	2037	16.3	23.1	66.2	105.6
<=2038	1,940	2,952	8,086	12,978	2038	16.3	23.1	70.2	109.6
<=2039	1,940	2,952	8,542	13,434	2039	16.3	23.1	74.1	113.5
<=2040	1,940	2,952	8,998	13,890	2040	16.3	23.1	78.1	117.5
<=2041	1,940	2,952	9,454	14,346	2041	16.3	23.1	82.1	121.4
<=2042	1,940	2,952	9,910	14,802	2042	16.3	23.1	86.0	125.4
<=2043	1,940	2,952	10,366	15,258	2043	16.3	23.1	90.0	129.4
<=2044	1,940	2,952	10,822	15,714	2044	16.3	23.1	93.9	133.3
<=2045	1,940	2,952	11,278	16,170	2045	16.3	23.1	97.9	137.3
<=2046	1,940	2,952	11,734	16,626	2046	16.3	23.1	101.9	141.2
<=2047	1,940	2,952	12,190	17,082	2047	16.3	23.1	105.8	145.2
<=2048	1,940	2,952	12,646	17,538	2048	16.3	23.1	109.8	149.1
<=2049	1,940	2,952	13,102	17,994	2049	16.3	23.1	113.7	153.1
<=2050	1,940	2,952	13,558	18,450	2050	16.3	23.1	117.7	157.1

	RS Incremental Counts			
	Rebate	Actuals	Model	Totals
2021	0	0	447	447
2022	0	0	439	439
2023	0	0	436	436
2024	0	0	422	422
2025	0	0	397	397
2026	0	0	402	402
2027	0	0	419	419
2028	0	0	435	435
2029	0	0	449	449
2030	0	0	456	456
2031	0	0	456	456
2032	0	0	456	456
2033	0	0	456	456
2034	0	0	456	456
2035	0	0	456	456
2036	0	0	456	456
2037	0	0	456	456
2038	0	0	456	456
2039	0	0	456	456
2040	0	0	456	456
2041	0	0	456	456
2042	0	0	456	456
2043	0	0	456	456
2044	0	0	456	456
2045	0	0	456	456
2046	0	0	456	456
2047	0	0	456	456
2048	0	0	456	456
2049	0	0	456	456
2050	0	0	456	456

	RS Incremental Capacity			
	Rebate	Actuals	Model	Totals
2021	0.0	0.0	3.9	3.9
2022	0.0	0.0	3.8	3.8
2023	0.0	0.0	3.8	3.8
2024	0.0	0.0	3.7	3.7
2025	0.0	0.0	3.4	3.4
2026	0.0	0.0	3.5	3.5
2027	0.0	0.0	3.6	3.6
2028	0.0	0.0	3.8	3.8
2029	0.0	0.0	3.9	3.9
2030	0.0	0.0	4.0	4.0
2031	0.0	0.0	4.0	4.0
2032	0.0	0.0	4.0	4.0
2033	0.0	0.0	4.0	4.0
2034	0.0	0.0	4.0	4.0
2035	0.0	0.0	4.0	4.0
2036	0.0	0.0	4.0	4.0
2037	0.0	0.0	4.0	4.0
2038	0.0	0.0	4.0	4.0
2039	0.0	0.0	4.0	4.0
2040	0.0	0.0	4.0	4.0
2041	0.0	0.0	4.0	4.0
2042	0.0	0.0	4.0	4.0
2043	0.0	0.0	4.0	4.0
2044	0.0	0.0	4.0	4.0
2045	0.0	0.0	4.0	4.0
2046	0.0	0.0	4.0	4.0
2047	0.0	0.0	4.0	4.0
2048	0.0	0.0	4.0	4.0
2049	0.0	0.0	4.0	4.0
2050	0.0	0.0	4.0	4.0

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 4-9

Docket No. 2021-143-E
Docket No. 2021-144-E

Date of Request: **September 1, 2021**
Date of Response: **September 10, 2021**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Melissa Adams, Manager Program Performance, and was provided to the SC Office of Regulatory Staff under my supervision.

Samuel J. Wellborn
Counsel
Duke Energy Carolinas, LLC & Duke Energy Progress, LLC

SC Office of Regulatory Staff
Fourth Audit Request for Records
and Information
DEC Solar as EE-Docket 2021-144-E
DEP Solar as EE-Docket 2021-143-E
Item No. 4-9
Page 1 of 1

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

4-9 Provide information on customer participation in the BYOT program. The information should include both participation and eligible population information identified by rate schedule. At a minimum, the response should show separate statistics for RE customers and non-RE customers.

Response:

In 2020, SC DEP averaged 140,537 Residential customers, of which approximately 93,579 (67%) were all electric. SC DEC averaged 520,401 Residential customers, of which 233,079 were in rate class RE (all electric). While BYOT is offered to all Residential customers, only a subset would meet the additional eligibility requirement of having an internet connected smart thermostat.

There are currently 19,927 DEP customers participating in BYOT. Using the above 67% estimate for all electric, it is estimated that 13,269 participants are all electric.

There are currently 29,878 DEC customers participating in BYOT, of which 8,920 are designated in the RE rate class.